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Biofuels and biochemicals production from forest biomass in Western Canada

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ABSTRACT

Biomass can be used for the production of fuels, and chemicals with reduced life cycle (greenhouse gas) emissions. Currently, these fuels and chemicals are produced mainly from natural gas and other fossil fuels. In Western Canada, forest residue biomass is gasified for the production of syngas which is further synthesized to produce different fuels and chemicals. Two types of gasifiers: the atmospheric pressure gasifier (commercially known as SilvaGas) and the pressurized gasifier (commercially known as RENUGAS) are considered for syngas production. The production costs of methanol, (dimethyl ether), (Fischer-Tropsch) fuels, and ammonia are \$0.29/kg, \$0.47/kg, \$0.97/kg, and \$2.09/kg, respectively, for a SilvaGas-based gasification plant with a capacity of 2000 dry tonnes/day. The cost of producing methanol, DME, F-T fuels, and ammonia in a RENUGAS-based plant are \$0.45/kg, \$0.69/kg, \$1.53/kg, and \$2.72/kg, respectively, for a plant capacity of 2000 dry tonnes/day. The minimum cost of producing methanol, DME, F-T fuels, and ammonia are \$0.28/kg, \$0.44/kg, \$0.94/kg, and \$2.06/kg at plant capacities of 3000, 3500, 4000, and 3000 dry tonnes/day, respectively, using the SilvaGas-based gasification process. Biomass-based fuels and chemicals are expensive compared to fuels and chemicals derived from fossil fuels, and carbon credits can help them become competitive.

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1. Introduction

Western Canada is one of the largest hydrocarbon bases in North America. Most commercially produced liquid fuels and chemicals are based on fossil fuels (e.g., natural gas, coal). Biomass is one of the main renewable energy sources that can be used to produce solid fuels (e.g., charcoal, pellets), liquid fuels (e.g., methanol, F-T diesel), gaseous fuels and chemicals (DME, H_2) [1–6]. The greenhouse gas (GHG) footprints of these fuels and chemicals are much lower than those of fossil fuels because biomass is nearly carbon neutral. Currently, in Western Canada forest residue is mostly collected along the roadsides and burnt to prevent forest fires [7]. Utilization of forest residue for energy production could replace the utilization of fossil fuel.

Currently, around the world biomass feedstocks are used mainly as fuel for generating power and heat; mostly using small scale production plants (20–80 MW) [8]. This study is based on the utilization of forest biomass to produce fuels and chemicals, specifically to produce syngas through gasification. Biomass gasification is a thermo-chemical conversion of biomass to a mixture of combustible gases (syngas) by heating biomass feedstocks in the presence of insufficient oxygen and/or steam. Syngas is a blend of H_2 and CO gases. There are some small scale biomass gasification plants which produce syngas for heat and power generation [9,10]. On the other hand, the syngas produced by natural gas/coal-based plants is commercially used for producing liquid fuel [5,11–13]. There is little data available on the techno-economic assessment of using forest residue for the production of fuels and chemicals. This study uses data from the Western Canada to develop techno-economic models. It integrates different technologies for producing fuels and chemicals from forest biomass and compares the overall cost of different fuel- and chemical- production technologies.

The data used in this study are specific to Western Canada. The key objectives of this study are:

- Characterizing different bioconversion pathways in terms of their operating and investment costs.
- Determining the cost of delivering forest residue to the syngas plant.
- Developing techno-economic models for determining the cost of producing biochemicals using syngas.
- Ranking biochemicals according to their cost of production.
- Developing cost curves to show the impact of scale on the cost of producing biochemicals.

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Nomenclature

ASU	air separation unit
BCL	Battelle Columbus Laboratory
BFB	bubbling fluidized bed
CFB	circulating fluidized bed
DME	dimethyl ether
F-T	Fischer-Tropsch
GHG	greenhouse gas
GTCC	gas turbine combined cycle
GTI	Gas Technology Institute
HHV	higher heating value
HRSG	heat recovery steam generation
HTS	high temperature shift
IGCC	integrated gasification and combined cycle
LTS	low temperature shift
MJ	mega joule
MPa	mega pascal
PSA	pressure swing adsorption

2. Current status of technology

There are different demonstration scale plants which gasify biomass in order to produce syngas [10,14,15]. Biomass gasification technologies are in different stages of development, demonstration, and commercialization. For example, Carbo-V is a combination of pyrolysis (heating of biomass in the absence of oxidants) and gasification followed by (Fischer-Tropsch) synthesis. Carbo-V was developed by CHOREN in Germany [16]. CHOREN plans to construct a forest-residue-based synthetic fuel production plant (23 000 tonnes/year) in France; it is scheduled to be commissioned by the end of 2014 [17], but so far little data are available on its long term testing. Data on its characteristics and costs are also not available. Rentech (Renewable Energy Technologies), which is a California-based company in Los Angeles, plans to build a SilvaGas-based synthetic fuel (640 barrels/day) and electricity (35 MWe) production plant in Rialto, CA; their start-up is scheduled for 2012 [18]. As well, in 2013, (Gas Technology Institute) will build a bench scale pilot plant (1 tonne/day) in Des Plaines, IL, which will produce gasoline and diesel from wood, agricultural residue, and algae [19]. A large number of companies and institutes are working on biomass gasification for producing heat, power, and fuels/chemicals; there is no commercial scale biomass gasification plant that produces chemicals, although some demonstrations have been done on a pilot scale. A list of companies which are focusing on biomass gasification process, their contact information, and the status of their technology are available upon request to the authors [20].

3. Scope and assumptions

The overall methodology of this work involves the development of a detailed techno-economic model based on demonstrated technologies currently available for producing high quality syngas from forest biomass. The detailed methodology of this study is given below.

- Data development on cost components and characteristics – This involves collecting data on various unit operations required to produce biochemicals from biomass-based syngas and data on the characteristics of various bioconversion pathways.
- Development of techno-economic model for estimation of cost – This involves developing techno-economic models capable of estimating the cost of producing each biochemical using the identified bioconversion process.
- Development of cost curves and ranking of biochemicals based on their cost of production – This involves developing of cost curves that show the impact of scale on the cost of production. The bioproducts are ranked in accordance with their cost of production.

The methodology for this work was scoped out and modified as the work progressed, and data were collected from a range of sources, including the published literature. The estimation of feedstock-related costs was based on consultations with researchers at various provincial and federal agencies working in this area. Some data on capital, operating, and maintenance costs were estimated in discussion with plant developers; the authors have extensive prior experience in estimating the cost of biomass-based power and pyrolysis projects and have already published in this area [1,2,4,6,7]. Once credible technologies and cost factors were identified, data intensive techno-economic models were developed. These techno-economic models are spreadsheet-based and very data intensive. These models were built using data on characteristics of feedstock, characteristics of conversion technologies and cost details related to different unit operations in conversion processes. These models were based on full life cycle costing, using an appropriate discount factor over a life cycle (30 years). This approach is comparable to the investment screening techniques used in the industry today. The results were analyzed to assess the potential for producing biochemicals from syngas. All the costs are in 2008 US$ unless otherwise noted, and an inflation rate of 2% is assumed.

Coal and natural gas are exclusively used for (Fischer-Tropsch) fuel production [12]. Syngas is produced from the gasification of coal or the steam reforming of natural gas for F-T synthesis. Therefore, syngas to liquid fuel production from fossil fuels is an established technology even at a large scale [12]. As well, the process for biomass feedstock handling, sizing, drying, and feeding have long been used in the pulp and paper industry and for the production of heat and power; these processes are commercially available today, however, there is still a need to improve these technologies in order to reduce the cost of production. Biomass gasification is in an early stage of development and demonstration, but is commercially used in some locations to produce heat by burning syngas in a boiler. Production of different fuels and chemicals requires first the generation of syngas and then its synthesis. Subsequent sections provide a brief description of the different biomass-based fuels and chemicals considered in this study and their properties, biomass feedstock processing, biomass gasification, and the syngas cleaning process. Later, syngas synthesis processes for producing different fuels and chemicals are explained.

4. Properties of biomass feedstock and selected fuels/chemicals

In this study, forest biomass residue is utilized for producing chemicals and liquid fuels. This forest residue is generated by logging operations. Currently, about 80% of forest residue is forwarded and piled on the roadside and burnt to prevent forest fires [7]. The properties of forest biomass feedstock are given in Table 1. “As received” forest biomass residue has a high moisture content (>45%) that requires heat during its gasification for drying, and for producing syngas stream with a high oxygen content, thus removing oxygen from the synthesizing processes [21]. On the other hand, a very low moisture content in biomass feedstock could result in fire during the drying process; the biomass may combust during the gasification process resulting in high H_2O and CO_2

Table 1
Properties of forest residues during transportation.

Items	Values
"As received" moisture content (%) [7]	45
Calorific value (MJ/kg) [1]:	
HHV	19.7
Density (wet kg/m^3) [24]	551
Moisture content after drying (%)	12
Calorific value at 12% moisture content (MJ/kg) [25]	17.05

formation [22]. Basically, a high H_2/CO ratio is required for the synthesis of syngas to produce fuels and chemicals. In order to achieve this, it has been assumed that the biomass feedstock supplied to the gasifier has a moisture content of 10–20%, the lower end of that range. Also feedstock size, which has a significant impact on the heat transfer mechanism, typically 20–80 mm; this provides a high and fast heat transfer rate which facilitates the feedstock's complete decomposition [23]. Pulverizing of biomass feedstock is a highly energy- and cost-intensive process compared to pulverizing coal; therefore, biomass is prepared for gasification in the production plant by three separate steps: feedstock grinding, drying, and feeding.

Biomass feedstock is harvested from the forest using felling, skidding, and chipping processes. After roadside chipping, it is transported to the biomass processing facility, where chips are unloaded from trucks into storage bins, with large chips being separated by sieves in a magnetic separation process [26]. Chips larger than 50 mm (2 inch) are passed through a hammer mill for further size reduction [22]. After grinding, conveyors are used to transport the chips into the dryer. Rotary biomass dryers are extensively used on a commercial scale in the pulp and paper industry [22,27]. In the rotary biomass drying process, heat for evaporating water from wet biomass feedstock can be supplied by preheated air, steam, or flue gas [28]. Note that, in the summer, the moisture content of forest residue after whole-tree harvesting is lower than 45%; this could reduce the cost of drying, because the forest residue has already dried in the forest. However, in this study, is it assumed that the feedstock has an average moisture content over the whole year.

Feeding dried biomass into the gasification reactor can be carried out by three types of feeder: a rotary valve feeder, a lock hoper system, or a plug feed system [27]. The type of feeding process selected depends on the scale of the operation, the power consumed by the feeding system, the inert gas consumed (i.e., operating cost), the pressure required, and the capital cost. For high pressure gasification, the lock hopper is a well established technology in spite of the high inert gas consumption needed for pressurized gasification [12]. Another option is the screw feeder, an already established technology for large scale biomass facilities, which can be used for atmospheric pressure gasification [27]. In this study, it is assumed that the lock hopper is used for RENUGAS and the screw feeder, for SilvaGas gasification. Both of these gasification processes are explained in the next section.

Biomass contains hydrogen and carbon which are the main building blocks of hydrocarbon. There are a number of chemicals/fuels which can be produced from biomass as are shown in Fig. 1. In this study, different biomass-based fuels and chemicals are analyzed which can be produced from the syngas generated by biomass gasification.

In this study, methanol, (dimethyl ether), (Fischer-Tropsch) fuels, and ammonia are the selected fuels and chemicals. These are currently produced mainly from natural gas, crude oil, and coal. The physical and chemical properties of fuels and chemicals produced from biomass feedstocks are similar to those of the fuels and chemicals derived from fossil fuels. Different properties of these selected fuels and chemicals can be found in different studies [32–38].

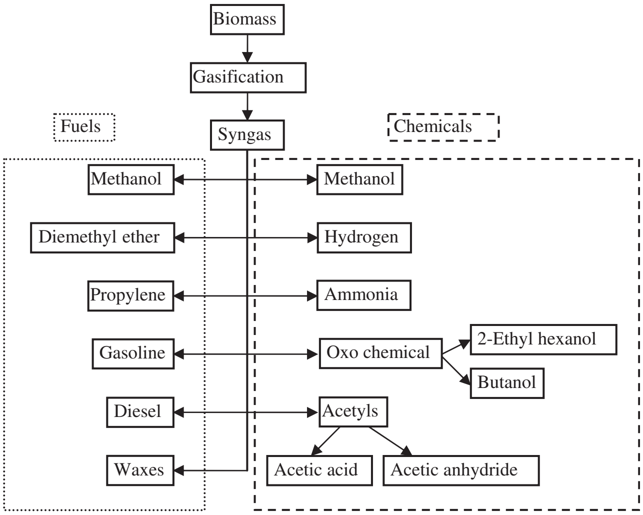

Fig. 1. Syngas-based fuels and chemicals produced from biomass [derived from 29–31].

5. Gasification and syngas clean up processes

Producing fuels and chemicals from biomass requires the production of syngas by the gasification process; the syngas then passes through different synthesizing processes for the production of fuels and chemicals. All of the cases which have been developed in this study require the generation of syngas from biomass through gasification.

This study is based on a fluidized bed atmospheric pressure gasifier developed by (Battelle Columbus Laboratory), which is commercially known as the SilvaGas process [10]. Also (Gas Technology Institute) has developed a pressurized gasifier, which is known as the RENUGAS process, commercially licensed by Carbona Corporation [39]. Both these gasification processes considered in this study have been demonstrated mainly for syngas production from biomass or from a blend of biomass and coal [10]. Limited data on characteristics and costs are available for assessing these gasifiers, both of which are considered in this study for the gasification of forest biomass. The operating parameters and characteristics of these gasification processes can be found in the literature [12,26,27,40–46].

The number of feedstock pretreatment and drying units and product gas cooling units depends on the number of gasification reactors; therefore, when the plant size exceeds the maximum size of the gasifier, multiple gasifiers and subsequently, multiple feedstock pretreatment and cooling processes are used. In this study, the maximum capacity of the atmospheric pressure gasifier is assumed to be 1000 dry tonnes/day [26], and that of the pressurized gasifier is assumed to be 2875 dry tonnes/day [12]. The type of gasification process, gas clean up and compression process varies depending on the process being used to synthesize the fuels and chemicals. The levels of different contaminants in syngas for different synthetic processes can be found throughout the literature [47–49].

6. Fuels and chemicals production processes

Biomass gasification is considered this study's syngas production process; different fuels and chemicals can be produced from

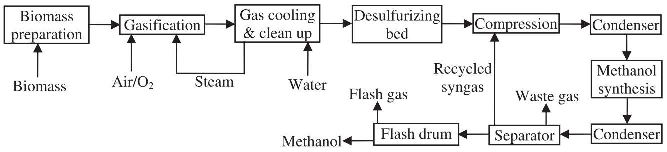

Fig. 2. Simplified flow diagram of methanol production from biomass gasification [derived from 2].

this syngas. The details of the production of different fuels and chemicals using biomass gasification are explained below.

6.1. *Methanol production*

Currently, natural gas, which has a concentration of high H_2, is used for the production of methanol. Syngas generated from biomass feedstock can pass through a fixed-bed reactor (gas-phase syngas passes through a fixed-bed filled with catalyst) or a slurry-bed reactor (liquid-phase catalysts are filled with liquid-phase inert oil in the reactor) [12,50]. Due to low conversion efficiency and high loss of catalyst in gas-phase reactor, the liquid-phase reactor is preferred for methanol production in large plants. Fig. 2 shows the process flow diagram of methanol production from biomass gasification.

Generally, the operating temperature and pressure during methanol synthesis are 220–240 °C and 5 MPa, respectively [3,51]. $CuO/Al_2O_3/ZnO$-based catalysts are used in the liquefaction of syngas for producing methanol; the formation of methanol occurs at a low temperature in the presence of these catalysts [3]. In this study, the maximum yield of methanol from biomass gasification (at 750 °C, 0.1 MPa pressure, steam/biomass flow rate of 0.4) is assumed to be about 39 wt% of the dry biomass feed rate (12.19 mol/kg of dry biomass) [3]. The methanol produced by the synthesis has a high temperature which is cooled to below 64 °C for separating liquid methanol from the gases.

6.2. *DME production*

DME is produced from the dehydration of methanol, whereas methanol is produced from the syngas. Fig. 3 explains the process of producing DME using the process of biomass gasification.

The inlet temperature and pressure of the syngas are about 245 °C and 6.51 MPa, respectively, and the temperature and pressure of the outlet stream of DME are about 260 °C and 6.25 MPa, respectively [12]. The catalysts used to produce methanol are $CuO/ZnO/Al_2O_3$, while γ-Al_2O_3, silica-alumina, or zeolite are used as dehydration catalysts [52]. The conversion rate of CO in a single step DME-synthesis reactor is about 14.6–30.2%, varying with the type of catalyst and the H_2/CO ratio in the reactor [12,52]. Both methanol synthesis and methanol dehydration can be achieved in the same reactor in a single step process using catalysts for both production and dehydration. The yield of DME using commercial methanol-synthesis catalysts and methanol-dehydration catalysts in a liquid phase reactor is 31–37% of the dry biomass feed [12,42,53]. The liquid DME is separated from the methanol and unconverted syngas and then stored at the production plant in storage tanks.

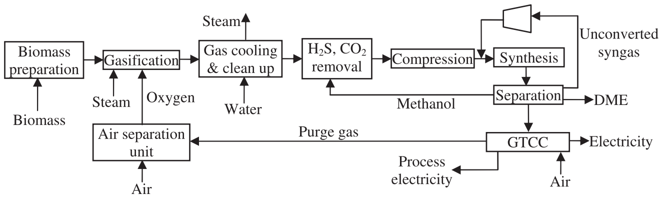

Fig. 3. Simplified flow diagram of DME production from biomass gasification [derived from 12].

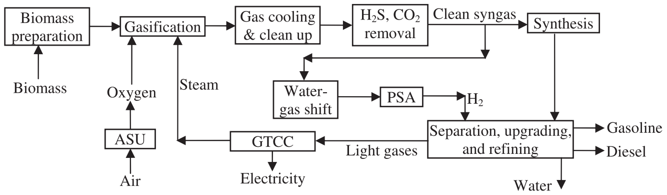

Fig. 4. Simplified flow diagram of F-T diesel production from biomass gasification [derived from 12].

6.3. *Fischer-Tropsch fuels production*

Currently, the F-T synthesis process is used to produce liquid fuels from natural gas or coal [5]. To produce liquid fuels from biomass-based syngas, pressurized gasification is preferred compared to atmospheric pressure gasification due to the latter's high H_2/CO ratio and low downstream equipment size [54]. The process of synthesizing F-T can be carried out in two types of reactors: gas-phase (or fixed-bed) and liquid-phase (or slurry-bed) [12,54–56]. Currently, liquid-phase reactors are commercially used for F-T fuel production because of their high heat transfer properties and low catalyst loss [54]. The F-T-synthesis process produces a blend of fuels which are shown in Fig. 4.

Basically, low-temperature synthesis (180–250 °C) leads to the production of large amounts of wax and diesel oil, whereas high-temperature synthesis (300–350 °C) produces alkenes and gasoline; the pressure of the F-T synthesis is around 2–4 MPa [56,57]. Both gasoline and diesel are produced from the F-T-synthesis process, and then upgraded and separated in a distillation tower. A high rate of heat transfer, which is accomplished by high contact between syngas and catalysts, results in about an 80% conversion rate of CO in the slurry-bed reactor, compared to 40% in the fixed-bed gas-phase reactor [54]. The F-T-synthesis process can be carried out in the presence of an iron or cobalt catalyst; cobalt-based catalysts are used commercially in slurry-phase reactors [57,58]. In this study, the yields of gasoline and diesel are assumed to be 5.17 wt% and 7.79 wt%, respectively [12,57,59,60], so, the equivalent yield of F-T fuel in the gasification reactor is about 12.96 wt% of the dry biomass feed rate.

6.4. *Ammonia production*

In the Haber-Bosch process, hydrogen fuel reacts with the nitrogen from air at high pressure and temperature generating

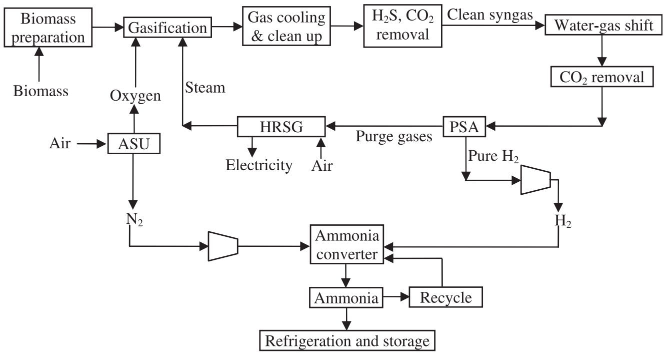

Fig. 5. Simplified flow diagram of ammonia production from biomass gasification [derived from 68].

Table 2

Assumption and costs parameters of fuels and chemical production plants.

Items	Value	Description
Harvesting cost of forest residues	\$11.25/dry tonne	The residues which consist of branches and tops are piled up by forwarder on the roadside, where these are chipped and transported by a B-train chip truck to the production plant [1,2,6]. The harvesting cost of forest residues estimated in this study is derived from an earlier study [7].
Field purchase cost of forest residues	\$4.8/dry tonne	Biomass feedstock is owned by the provincial government, and a premium cost is paid for removing fuels from the field [7]. Silviculture cost is not considered because it is incurred during the whole forest harvesting during logging operation.
Transport cost of forest residues	\$25.8/dry tonne	The area, which is assumed to be circular, is harvested sustainably for a 30 years fuel and chemical production plant life. The transportation distance is the average radius of the circle along with a geometrical factor and a tortuosity factor [66]. In this study, values of geometrical and tortuosity factors are assumed 2.3 and 1.5, respectively. The yield of forest residues is assumed 0.247 dry tonnes/ha [7]. The transportation cost of forest residues for a plant size of 2000 dry tonnes/day is \$25.8/dry tonne for an average transportation distance of 136 km.
Delivered cost of forest residues	\$41.8/dry tonne	The delivered cost of forest residues consists of biomass piling and forwarding costs, chipping cost, transportation cost, and premium cost. In this case, harvesting (piling, forwarding, and chipping) and premium costs of forest residues (\$16/dry tonne) are the fixed cost, i.e., it does not change with scale and distance. Transportation cost of forest residues (\$25.8/dry tonne) is a variable cost, and cost is estimated for a plant size of 2000 dry tonnes/day [2,6].
Storage cost of forest residues at plant site	\$3.8/dry tonne	There is a need for storage facility that would store biomass residues for a certain period of time to supply biomass when roads are inaccessible. There are different storage methods based on the feedstocks such as storage in open air for wood chips, storage in bunker for wood pellets or dried wood chips, and storage in tanks for liquid fuels [67]. In this study, forest residues chips are stored at the biomass processing facility for 3 months periods, and this cost includes loading and unloading costs of wood chips [67].
Capital cost	Table 3	Forest residues-based fuels and chemical production plants are located in remote areas which increase the capital cost due to its high construction cost. Factor to reflect capital cost impact for remote location is assumed to be 10%. In this study, it is assumed that the plant life is 30 years. Spread of costs during construction are assumed 8% (1st year), 60% (2 nd year), and 32% (3rd year) based on an earlier study [26]. First year cost is associated with planning, acquiring permits, and engineering, while 2nd and 3rd years costs are equipment purchase and construction costs [67,68].
Operating costs	4% of plant capital cost	The operating cost of a plant is divided in two sections: variable operating cost and fixed operating cost. The variable operating costs include costs of catalysts, waste water treatment, chemicals, electricity, etc., and it increases almost linearly with increasing plant size. The variable operating cost is assumed 4% of plant capital cost [12].
Maintenance cost	2% of capital cost	Synthesis processes for biomass are not commercially established today compared to natural-gas-based plant. Therefore, a higher value in maintenance cost for biomass compared to conventional fossil-fuel-based plant is assumed to be 2% of capital cost based on different literatures [12,26,60,68,69]. Note that, in the variable operating cost, small quantity of diesel fuel and/or natural gas that is required during the plant start-up operation is not considered in the development of the cost models as it is a negligible cost factor.
Average annual labor cost including benefits:		The administrative and labor costs are estimated based on the number of employee that required operating the plant. The number of operating staff and administrative staff are assumed to be 50 and 4 with an hourly salary of \$40 and \$64 for a plant capacity of 2000 dry tonnes/day (includes benefits), respectively (these costs are based on earlier studies) [2,6]. The increase in the number of operating staff for an increase of plant size of 500 dry tonnes/day is assumed to be 5, while the administrative staffs are assumed fairly constant. Note that, the number of employee required for different fuels and chemicals production plants are assumed same for both of the gasification technologies of a fixed plant size.
Operating staff	\$40/hour	
Administrative staff	\$64/hour	
Connection of the gasification plant to the transmission grid		In this study, it is assumed that there is an existing electricity production plant based on gasification or combustion of biomass from where electricity is available. Hence, cost of transmission line is not included in this study.
Plant reliability and start-up profile:		A conservative approach is taken into account with 70%, 80%, and 85% operating factors for year 1, year 2, and year 3 and onward, respectively based on earlier studies for biopower generation [7].
Year 1	70%	
Year 2	80%	
Year 3	85%	
Ash disposal cost:		Forest residue has certain amount of ash which is deposited in the field near the biomass processing plant as assumed in this study [7]. The amount of ash produced is estimated from the proximate or ultimate analysis of forest residues, and ash is transported to a distance of 50 km by truck and is disposed in the forest. Therefore, ash disposal cost includes cost of ash transportation (\$0.18/dry tonnes/km) and cost of ash spreading (\$25.22/dry tonne/ha) in the field [1,70].
Cost ash transportation	\$0.18/dry tonnes/km	
Cost of ash spreading	\$25.22/dry tonne/ha	
Reclamation cost	20%	Generally, capital cost expenditure for the first 6 months or 1st year is low compared to the 2nd and 3rd year expenditures because most of the costs in the former case are related to planning, design, and engineering cost, which do not have any salvage value at the end of the plant life. While in the latter case, most costs are associated with equipment purchase, construction, and installation cost. Therefore, the reclamation cost, which is the decommissioning cost of the plant, is assumed to be 20% of the capital cost expenditure in the 2nd and 3rd years of plant construction cost.
Aggregate pre-tax return on investment	10%	Since biomass feedstocks are renewable fuels that require substantial support of government it is assumed that the capital cost investment is a blend of equity and debt [2,6,7,26].

ammonia [61]; therefore, gasification of biomass can be used for the production of hydrogen fuel. Fig. 5 shows the theoretical steps for producing ammonia using biomass.

Once biomass gasification produces hydrogen, pure hydrogen and pure nitrogen react at high pressure (8–20 MPa) and temperature (350–480 °C) in the presence of an iron-based catalyst in an ammonia-synthesis reactor [63–65]. The entire H_2 and N_2 mixture does not convert to ammonia; unreacted gases go through the synthesis loop for ammonia production. The conversion rate of N_2 and H_2 per pass in the ammonia-synthesis reactor is about 25–35% [63], therefore, unconverted H_2 and N_2 are recycled back to the synthesis reactor. Commercially, three types of technology are used

Table 3
Capital cost components of forest residues-based gasification plants.

Gasifier	Subsections	Capital costs[a] (million $)
SilvaGas	Feedstock pretreatment[b]	42.92
SilvaGas	Gasification and tar reforming[b]	48.46
SilvaGas	Gas clean up, compression, and water-gas shift[c]	58.22
SilvaGas	Steam and power production[d]	33.06
SilvaGas	Cooling tower and other utilities[e]	8.13
SilvaGas	Land procurement[f]	4.30
RENUGAS	Feedstock pretreatment[g]	86.55
RENUGAS	Gasification and oxygen production[g]	163.84
RENUGAS	Gas clean up and compression[h]	106.26
RENUGAS	Power generation[i]	83.35
RENUGAS	Land procurement[f]	9.77

[a] All costs are presented for a plant size of 2000 dry tonnes of forest residues/day, and costs are in 2008 US$. Costs are estimated for the first-of-a-kind plant that includes direct and indirect cost, installation cost, and balance of plant cost, and costs are higher compared to an Nth case plant. Capital cost also includes a penalty for remote location and the other factor for increasing plant life in 30 years.

[b] Feedstock pretreatment includes cost of conveyor, grinder, storage, dryer, metal removal, and feedstock feeding system. SilvaGas gasification includes costs of atmospheric pressure gasification system, tar reformer, cyclones, syngas coolers, and air blowers [26].

[c] Acid gases from the syngas stream is separated by catalytic oxidation process (LO-CAT®), and ZnO is used to reduce sulfur level significantly [48]. The syngas is compressed with 5-stage centrifugal compressor [26]. Both high temperature shift (HTS) and low temperature shift (LTS) reactors are used to increase the H_2/CO ratio [12].

[d] Boilers costs are included in the gas clean up and reforming sections. Here, cost includes steam turbines, pumps, and different drums [26].

[e] Costs include mainly cooling towers, pumps, and different storage tanks [26].

[f] Land procurement cost is taken as 2% of the total equipment investment cost [26].

[g] Feedstock pretreatment cost includes cost of conveyor, grinder, storage, dryer, metal removal, and feedstock feeding system. RENUGAS gasification includes costs of pressurized (3 MPa) gasification system and oxygen generation plant [60,71].

[h] Wet gas clean-up process includes Rectisol® unit that also separates CO_2 from the acid gas stream and produces sweet gas stream [12]. Rectisol®, an acid gas removal unit that uses physical solvents to remove impurities from gases, is commercially used in the industry [48].

[i] During the syngas cooling process, heat is removed through the steam generation process, and all of the syngas is not converted to final products. Therefore, steam and unconverted syngas are used in the steam turbine and gas turbine for electricity production that meets the demand of electricity of the plant, and surplus is supplied to the grid [12,71].

primarily for ammonia production: the Haldor Topsøe process (Denmark), the Kellogg Brown and Root process (USA), and the Uhde GmbH process (Germany) process [63]. Currently, an iron-based catalyst is used in the reactor bed along with promoter (metal oxides) to produce ammonia [61,64]. In this study, all the costs are estimated for an iron-based catalyst in an ammonia converter. The yield of ammonia from biomass varies depending on the reactor configuration and type; the conversion rate of H_2 and N_2 is low (20–30%) per cycle; therefore, unconverted gases are recycled back to the ammonia-synthesis reactor to increase the yield. In this study, the yield of ammonia is assumed to be 84.2% of the hydrogen gas flow in the ammonia converter or 7.02% of the dry biomass feed rate in the gasifier [62].

7. Cost analysis

Table 2 explains the assumptions and cost values which were considered while developing the cost models for the selected fuels and chemicals. Table 4 lists the capital costs of different synthesizing processes.

Table 4
Capital costs of different synthesis processes.

Items	Capital costs[a] (million $)
Methanol synthesis[b]	48.37
DME synthesis[c]	180
F-T synthesis and upgrading[d]	102.52
Water-gas shift reaction, CO_2 removal, and PSA for ammonia production[e]	91.4
Haber-Bosch synthesis loop for ammonia production[f]	81.26

[a] All costs are presented for a plant size of 2000 dry tonnes of forest residues/day, and costs are in 2008 US$. Costs are estimated for the first-of-a-kind plant that includes direct and indirect cost, installation cost, and balance of plant, and costs are higher compared to an Nth case plant.

[b] Liquid phase methanol synthesis process, which has high syngas conversion efficiency [12,71].

[c] Liquid phase DME synthesis process which would have high syngas conversion efficiency [12,71].

[d] Liquid phase F-T synthesis reactor, which has high syngas conversion efficiency [12,71]. Cost also includes hydrogen and hydrocarbon recovery units, wax, distillate, and naphtha hydrotreater, naphtha reformer, CO shift reactor, and compressor [12].

[e] To maximize of H_2 fuel production, high and low temperature water-gas shift reactors are used that increase H_2 fuel concentration and reduce CO concentration in the syngas stream [12]. Large amount of CO_2 along with H_2S is separated from the syngas stream by Rectisol® unit that also decreases the size of PSA unit for the separation of H_2 gas from the syngas stream [12,71]. PSA unit separates H_2 from the syngas stream which contains mainly CO_2, water, CO, CH_4, and small amount of small-chain hydrocarbons [12]. The separation efficiency is about 85–87% with purity of 99.99% [26].

[f] Ammonia is produced in the Haber-Bosch synthesis loop which includes compressors, reactor filled with catalyst, and refrigeration cycle for cooling ammonia; cost is estimated based on the capacity of the ammonia production [62]. The electricity consumption of the compressor motor is estimated from the pressure of the inlet gas.

8. Results and discussions

8.1. Production cost

Cost of production is estimated for plant capacities in the range of 200–10 000 dry tonnes/day. Electricity is also produced from different conversion processes; however, emphasis is put on maximizing the production of different fuels and chemicals.

Tables 5 and 6 give the production costs of selected products for the SilvaGas and RENUGAS gasification processes, respectively. For both the SilvaGas- and RENUGAS-based conversion processes, it is apparent that the capital cost, operating cost, and forest biomass transportation cost are the key contributors. It is also noteworthy that capital cost's contribution to the total production cost is much higher in RENUGAS-based plant than in SilvaGas-based plants. The production cost of fuel is therefore higher in RENUGAS-based plants.

Table 5
Production costs of different fuels and chemicals for SilvaGas gasification (2000 dry tonnes/day).

Cost components	Methanol ($/kg)	DME ($/kg)	F-T diesel blend ($/kg)	Ammonia ($/kg)
Capital	0.10	0.19	0.35	0.63
Operating	0.06	0.10	0.20	0.68
Maintenance	0.02	0.04	0.07	0.13
Harvesting	0.03	0.04	0.09	0.16
Transportation	0.07	0.09	0.21	0.39
Storage	0.00	0.00	0.01	0.01
Royalty	0.01	0.01	0.04	0.07
Ash disposal	0.00	0.00	0.00	0.01
Total cost ($/kg)	0.29	0.47	0.97	2.09
Total cost ($/L)	0.23	0.31	0.78	1.42
Total cost ($/GJ)	14.48	16.34	21.79	110.76

Table 6
Production costs of different fuels and chemicals for RENUGAS gasification (2000 dry tonnes/day).

Cost components	Methanol ($/kg)	DME ($/kg)	F-T fuel blend ($/kg)	Ammonia ($/kg)
Capital	0.20	0.32	0.70	1.23
Operating	0.10	0.16	0.34	0.60
Maintenance	0.04	0.06	0.14	0.25
Harvesting	0.03	0.04	0.09	0.16
Transportation	0.07	0.09	0.21	0.39
Storage	0.00	0.00	0.00	0.01
Royalty	0.01	0.02	0.04	0.07
Ash disposal	0.00	0.00	0.01	0.01
Total cost ($/kg)	0.45	0.69	1.53	2.72
Total cost ($/L)	0.36	0.45	1.22	1.86
Total cost ($/GJ)	22.67	23.71	34.08	98.57

Table 7
Capital cost characteristics for different fuels/chemicals at 2000 dry tonnes/day.

Items	Gasification technology	Capital cost/unit output ($/kg)	Capital cost/unit plant size ($1000/dry tonne biomass per day)
Methanol	SilvaGas	0.04	130
Ammonia	SilvaGas	0.24	156
F-T diesel	SilvaGas	0.13	160
DME	SilvaGas	0.07	203
Methanol	RENUGAS	0.07	266
Ammonia	RENUGAS	0.47	304
F-T diesel	RENUGAS	0.27	319
DME	RENUGAS	0.12	350

The production costs of methanol, DME, F-T diesel, and ammonia are shown for various plant capacities (dry tonnes biomass/day) in Fig. 6. All of these study's figures show some common trends. The concept that is illustrated by this one is that there is a trade-off between the capital cost per unit of output and the transportation cost of forest biomass. The capital cost per unit of output decreases for production plants as the capacity of the plants increases; this is due to economy of scale benefits. On the other hand, the transportation cost of biomass goes up with increasing plant size, because biomass is collected from a larger area and this results in a longer transportation distance. Other costs such as maintenance cost, biomass harvesting cost etc. do not change as plant scale changes (i.e. the $ per unit of output does not change with plant scale), so there is a trade-off between these two costs. This gives rise to the curve shown in Fig. 6. The common trends shown in Fig. 6 are:

- The cost of producing each product decreases rapidly from a plant capacity of 200 to about 3000 dry tonnes/day for the SilvaGas-based gasification process. In Westen Canada, the benefits due to economy of scale in a capital cost outweigh the penalty of increased transportation cost, resulting in a decrease in total production cost.
- The cost of producing each product decreases rapidly from a plant capacity of 200 to about 5000 dry tonnes/day for the RENUGAS-based gasification process. This is again due to same reason: economy of scale benefits trump the penalty of increased transportation cost.

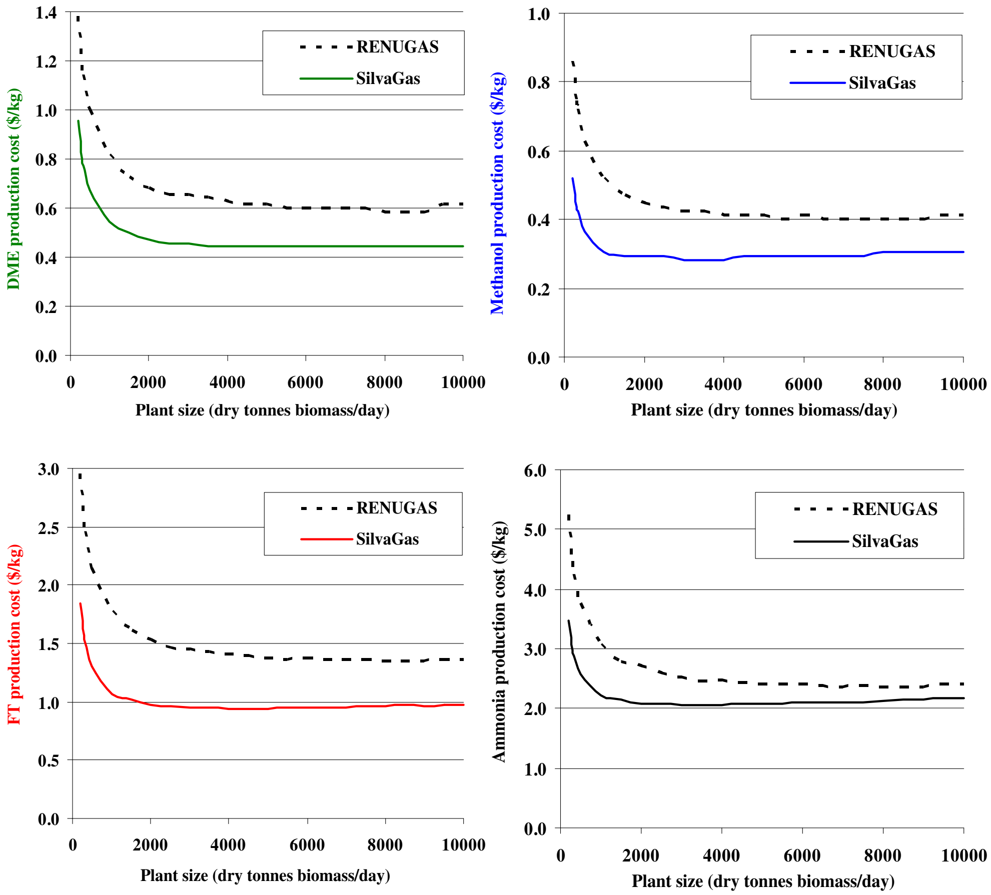

Fig. 6. Production costs of different fuels/chemicals at various plant sizes.

Table 8
Cost of methanol from various sources.

Feedstock	Capacity (tonne/day)	Technology	Cost of methanol $/kg ($/L)	Cost year	Country	Study
Biomass syngas	613–970	Synthesis process	$0.20–$0.27 ($0.16–$0.21)	2001	The Netherland	[43]
Biomass syngas	57–196	Synthesis process	$0.24–$0.30 ($0.19–$0.24)	1999		[72]
Biomass syngas	705–1004	Synthesis process	$0.21–$0.34 ($0.17–$0.27)	1991	USA	[73]
Biomass syngas	790–1110	Synthesis process	$0.22–$0.44 ($0.17–$0.35)	1993		[74]
Biomass syngas	717–4577	Synthesis process	$0.22–$0.42 ($0.17–$0.33)	1990	USA	[75]
Natural gas		Synthesis process	Euro 0.08–0.90 (Euro 0.06–0.71)	2005	Germany and Austria	[76]
Coal			Euro 0.11–0.12 (Euro 0.09–0.10)			
Biomass		Biomass gasification and methanol synthesis	Euro 0.32–0.40 (Euro 0.25–0.32)			
Natural gas	10000		$0.04 ($0.03)	2008	Germany	[77]
	2000		$0.11 ($0.09)			
Coal syngas	14439	Synthesis process	$0.17 ($0.13)	1982	USA	[78]
Coal syngas	5067	Synthesis process	$0.18 ($0.14)	1979		[79]
Coal syngas	1996	Synthesis process	$0.11 ($0.09)	1979	USA	[80]
Coal syngas	6395	Synthesis process	$0.18 ($0.14)	1979		[81]
Coal syngas	886	Synthesis process	$0.15 ($0.12)	1987	USA	[82]
Coal syngas	5000–10000	Synthesis process	$0.16–$0.20 ($0.13–$0.16)	1984	USA	[83]

Table 9
Cost of dimethyl ether (DME) from various sources.

Feedstock	Capacity (tonne/day)	Technology	Cost of DME $/kg ($/L)	Cost year	Country	Study
Natural gas	7300		$0.09 ($0.06)		Middle East	[84]
Natural gas			$0.11 ($0.07)		Japan	
Biomass	32	Gasification/synthesis	$0.43 ($0.29)	2009	China	[85]
Coal		Synthesis + electricity production (IGCC)	$0.17–$0.19 ($0.11–$0.13)	2005	Italy	[86]
Natural gas			$0.33 (0.22)		USA	[61]

- The cost of production is always higher for the RENUGAS gasification process because its capital and operating costs are higher than those of SilvaGas-based gasification plants.
- At first, production cost decreases rapidly as plant capacity increases because the benefits due to economy of scale are higher for capital costs than is the increase in transportation cost.
- The cost of production becomes almost constant when a plant can process more than 3000 dry tonnes/day (if Silva-Gas-based) or 5000 dry tonnes/day (if RENUGAS-based). This is because increasing plant size increases feedstock harvesting area (i.e., feedstock transportation cost), therefore the benefit from economy of scale is approximately equal to the rise in transportation cost.

Table 7 lists in ascending order the capital cost intensity of different plants. For SilvaGas gasification, the capital cost per unit of plant capacity is lowest for methanol followed by ammonia, F-T fuels, and DME. The production costs of different fuels and chemicals follow the same order shown in Tables 5 and 6. Capital cost is higher for RENUGAS-based plants than for SilvaGas-based plants, whereas yields of different fuels and chemicals from both SilvaGas and RENUGAS are almost the same. As a result, production cost ($/kg) is lower for SilvaGas-based gasification plants. The molar ratio of H_2/CO in syngas and the pressure of syngas are low in SilvaGas gasification plants; however, resulting in extra steps for syngas compression and water–gas–shift reaction. Basically, synthesis is an exothermic process which is favored when there is high pressure and high heat removal. Such factors result in a high conversion rate.

8.2. Comparison of production costs with convention fuels and chemicals

The costs reported in the literature were determined for different fuels and chemicals for a range of sizes. These costs are available at a number of sizes and it is not clear if these are at the optimal scale; hence, in this study, we summarize these costs from

Table 10
Cost of Fischer-Tropsch fuel from various sources.

Feedstock	Capacity (BBL/day)	Technology	Cost of F-T fuel $/kg ($/L)	Cost year	Country	Study
Natural gas			Euro 0.31 (0.23)	2005	The Netherland	[5]
Bituminous coal			Euro 0.58 (0.43)	2005		
Canadian FR			Euro 1.12 (0.83)	2005		
Biomass	1216–2026		$0.56–$1.29 ($0.42–$0.97)		The Netherland	[56]
Biomass	486–1378		$0.39–$0.56 ($0.29–$0.42)			[72]
Biomass	1357–1715		$0.35–$0.61 ($0.0.26–$0.46)			[87]
Natural gas			$0.68 ($0.51)		USA	[61]
Coal			$0.60 ($0.45)			

Table 11
Cost of ammonia from various sources.

Feedstock	Capacity (tonne/day)	Technology	Cost of Ammonia ($/kg)	Cost year	Country	Study
Natural gas	1000		$0.16		USA	[88]
Natural gas	1387	Steam methane reforming	$0.56	2007	USA	[89]
Coal	1650	Coal gasification with sequestration	$0.32			
	1817	Coal gasification without sequestration	$0.28			
	2080	Advanced gasification with sequestration	$0.15			
Natural gas	1400	Steam methane reforming	$0.69	2007	USA	[90]
Natural gas	2004	Steam methane reforming	$0.52	2007	USA	[91]
		Steam methane reforming with sequestration	$0.56			
Coal	1626	Coal gasification with sequestration	$0.43			
	1499	Coal gasification without sequestration	$0.37			
Coal	4524	Coal gasification with sequestration	$0.32	2007	USA	[92]
	4524	Coal gasification without sequestration	$0.28			
Biomass	736	Gasification & Haber-Bosch process	$0.63	2007	USA	[93]
Biomass	384	Pyrolysis	$0.57	2007	USA	[94]
	1022	Gasification	$0.49			
Brava cane	91–363		$0.21–0.31	1981		[95]
Natural gas	900		$0.22	1980		
Resid	900		$0.27	1980		
Coal	900		$0.31	1980		
Natural gas	–	Steam methane reforming	$0.50	2007		[96]
Vacuum resid	–		$0.25	1996		
Coal	–	Coal gasification without sequestration	$0.37	2007		

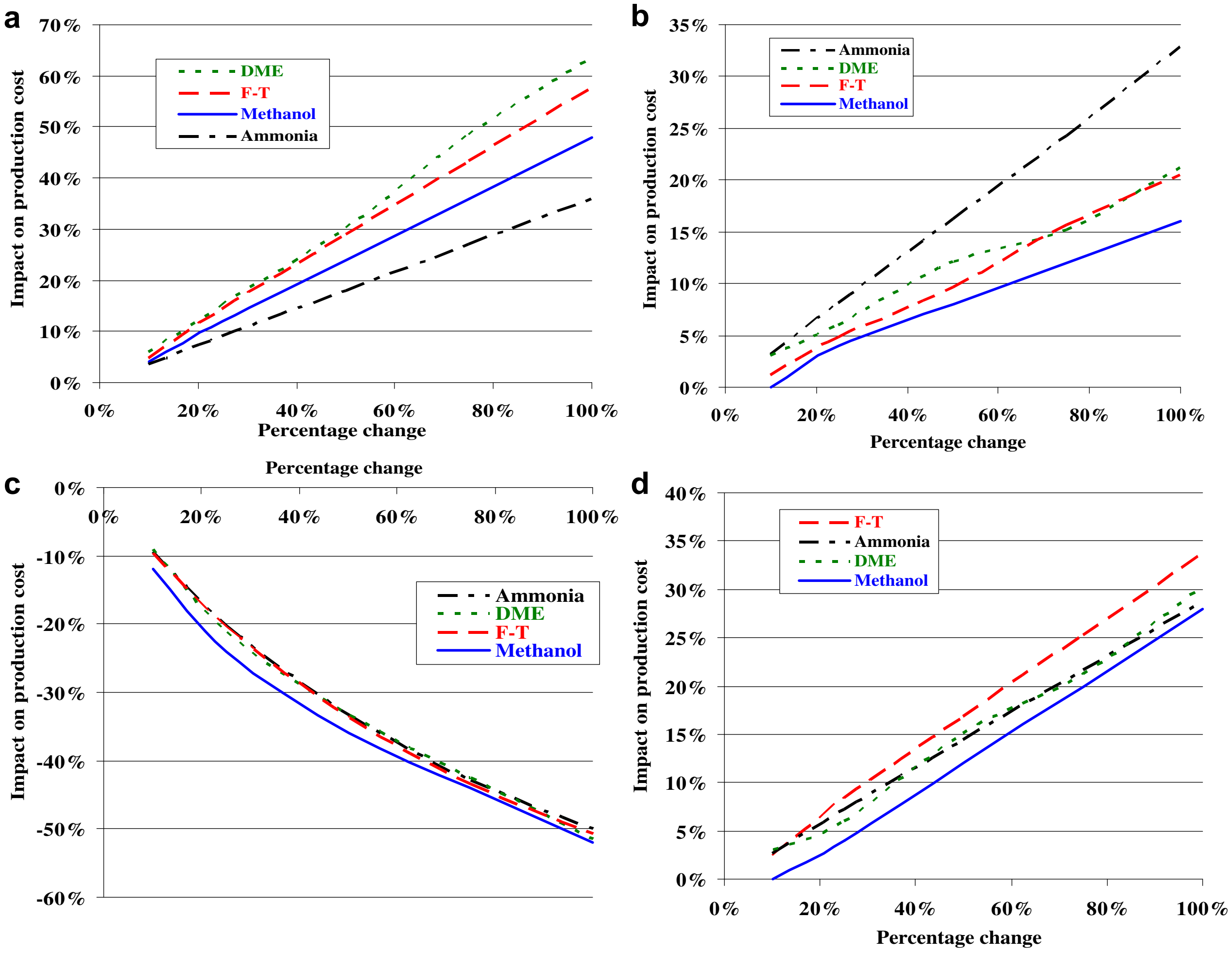

Fig. 7. Key sensitivity of fuels/chemicals production in SilvaGas gasification process: (a) capital cost, (b) operating cost, (c) fuels/chemicals yield, (d) feedstock delivery cost.

the literature ranging them and comparing the costs estimated in this study with the range of values reported in the literature. The cost of producing conventional methanol is not fixed; it changes with market demand and supply, feedstock type and price, as well as type of synthesis reactor (slurry-phase vs. gas-phase). It is most economical to produce methanol from natural gas, followed by coal and biomass. Table 8 shows the cost of producing methanol from different feedstocks in various jurisdictions, utilizing a range of technologies. The cost of methanol varies significantly depending on the production process, the cost of feedstock, and the scale of production. As shown in Table 8, the cost of methanol from natural gas is about $0.03–$1.20/L for plant capacities up to 10 000 tonnes per day; methanol from coal costs about $0.09–0.16/L for plant capacities up to 10 000 tonnes per day; methanol from biomass costs about $0.17–0.95/L for plant capacities in the range of 57–4577 dry tonnes/day. The range of costs is wide because there is significant variation in the cost of feedstock in different jurisdictions and over time. In this study, the estimated cost of methanol in Western Canada is $0.23/L for a plant capacity of 2000 dry tonnes/day; this is more expensive than natural-gas-based and coal-based methanol.

Table 9 gives the cost of DME based on various studies. DME is produced from methanol so that production cost of DME is slightly higher than that of methanol when methanol is produced from the same feedstock and in a plant of similar size. As with methanol, the cost of natural gas is also a significant factor in the cost of producing DME. The production cost of DME is in the range of $0.06 to $0.22/L from natural-gas-based feedstock. In this study, the lowest cost of DME for Western Canada is $0.28/L for a plant capacity of 3500 dry tonnes biomass/day.

The yearly average price of gasoline and diesel was around $0.72/L in the Province of Alberta, and depending on demand and petroleum supply during the time period analyzed. Searcy [34] reported the relation between crude oil price and diesel (Equation (1)) and gasoline prices (Equation (2)). These are given in Equations (1) and (2). Based on Equation (2), a $0.72/L price of gasoline corresponds to a crude oil price of $92 per barrel.

$$Y(\$\ \text{per litre diesel}) = 0.0063X + 0.184 \tag{1}$$

$$Y(\$\ \text{per litre gasoline}) = 0.0067X + 0.105 \tag{2}$$

where X is the oil price ($ per barrel).

On the other hand, the cost of F-T fuels produced from natural gas ranges from $0.23–$0.51/L and for coal it ranges from $0.43–$0.45/L. These are higher than for conventional gasoline and diesel (Table 10). Note that the cost of F-T fuel relies on the cost of natural gas or coal and also on the scale of the production plant. Generally, large plants can produce fuels at a lower cost. In this study, the cost of F-T fuels for Western Canada is $0.75/L for a plant capacity of 3000 dry tonnes biomass/day. The high cost is due to high feedstock delivery and pretreatment costs, lower yield of fuels compared to natural gas- or coal-based F-T diesels, and high capital cost.

Ammonia is widely produced for urea production, mostly from natural gas and coal. Table 11 gives the cost of producing ammonia from different feedstocks using a range of processes in different jurisdictions. Based on the literature review data given in Table 11, the cost of producing ammonia from natural gas is around $160–$690/tonne; it changes rapidly with the price of natural gas price and the capacity of the plant in the range of 900–2000 tonnes/day. The cost of producing ammonia from coal is in the range of $150–$430/tonne for plant capacities of 900–4524 tonnes/day. In this study, the cost of producing ammonia from biomass is $2064/tonne for a plant capable of processing 3000 dry tonnes biomass/day. The cost is very high because of the high cost of producing hydrogen from biomass.

8.3. Sensitivity analysis

Gasification of forest residue is analyzed for various fuel/chemical production processes. Data for all the cost components are derived mainly from different studies. This section analyzes the input-data variation on overall cost of production for different fuels and chemicals. Sensitivity analyses are performed for both the SilvaGas and RENUGAS gasification processes. Fig. 7 shows the key results of the sensitivity analysis for the SilvaGas gasification process. For all the selected fuels/chemicals, the cost of production could be reduced by reducing capital cost and increasing the process' yield of fuels/chemicals. The impact on production costs for both of the gasification processes is almost the same, therefore, only the sensitivity analyses of the SilvaGas gasification process are shown in Fig. 7. The impact on overall production cost of changes in biomass yield, harvesting cost, transportation cost, and operating cost is low. Production cost varies linearly with the operating cost and feedstock delivery cost of the plant whereas variations in production cost do not correspond linearly with changes in the yield of fuels and chemicals from the feedstock. The rate of variation in the cost of producing fuels and chemicals changes much faster than do other parameters studied in this sensitivity analysis. It can thus be concluded that, to compete with conventional production processes involving fuels/chemicals, it is necessary to improve processes to raise conversion efficiency and lower capital cost.

Table 12
Life cycle GHG emissions and carbon credits for biofuel and biochemical.

	Methanol	DME	FT-diesel	Ammonia
Life cycle emission from fossil fuel (kg CO_2/kg of product):				
Coal			4.29–4.63 [99]	
Natural gas	1.57 [97]	0.79 [98]	1.40–2.21 [99]	–[c]
Life cycle emission from biomass (kg CO_2/kg of product)[a]	0.0328	0.0259	0.0108	0.006
Life cycle cost from fossil fuel ($/kg):				
Natural gas	0.16–0.25 [61]	0.35 [61]	0.65 [61]	0.57–0.59 [89]
Coal	0.29–0.59 [61]	0.18–0.20 [86]	0.57 [61]	0.37–0.43 [90]
Life cycle cost (minimum) from biomass ($/kg)	0.28	0.44	0.94	2.06
Carbon credit ($/tonne of CO_2 equivalent)[b]	50	120	70	–

[a] Life cycle emissions for biohydrogen production from forest biomass is 1.01 kg of CO_2/kg of H_2, which includes forest biomass production, transportation, and biohydrogen plant construction and decommission [2]. It is assumed in this study, that the emissions during construction of plants for production of all biofuels and biochemicals are same as during the construction of H_2 production plant. Based on the biohydrogen production yield, 12 kg dry forest biomass is used for producing 1 kg of H_2, which results in 0.08417 kg of CO_2 emission/kg of dry forest biomass [2].

[b] The carbon credit is calculated taking the average value from the range of the cost and emission data. The carbon credit is estimated based on natural gas based methanol, DME, and FT-diesel.

[c] Not available.

8.4. Carbon credits

Table 12 shows the emission characteristics and carbon credits required for biomass-based fuels and chemicals. The carbon credits (\$/tonne of CO_2) in Table 12 show the incentive required to make biomass-based fuels and chemicals as economical natural gas based fuels and chemicals in Western Canada. The carbon credits required for making biomass-based methanol, DME, and FT-diesel competitive are \$50, \$120, and \$70 per tonne of CO_2, respectively.

9. Conclusion

In this study, gasification of forest residue is considered for syngas production, and further processing this in order to produce different fuels/chemicals. The cost of producing methanol, DME, F-T fuels, and ammonia are \$0.29/kg, \$0.47/kg, \$0.97/kg, and \$2.09/kg, respectively, for a SilvaGas-based gasification plant capable of processing 2000 dry tonnes/day. The fuels and chemicals from a RENUGAS-based plant cost more to produce than do those from a SilvaGas-based plant, because capital costs are higher for the RENUGAS plant. The minimum cost of producing methanol, DME, F-T fuels, and ammonia is \$0.28/kg, \$0.44/kg, \$0.94/kg, and \$2.06/kg for SilvaGas-based gasification plants with capacities of 3000, 3500, 4000, and 3000 dry tonnes/day, respectively. In comparison with fuels and chemicals from conventional feedstocks, biomass-based fuels and chemicals are expensive; however, life cycle emissions from biomass-based fuels and chemicals are lower than those from fossil-fuel-based fuels and chemicals. Incorporating carbon credits into production cost could reduce the selling price, enabling these environmental-friendly fuels to compete with fossil-fuel-based products.

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